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By

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Abstract: The authors study the investment incentives of energy policy in Germany and how this affects competition, the environment and supply adequacy. First, after a long period of 'self-regulation', the new Energy Act of 2005 installs a regulator and network regulation. Second, Germany has a strong agenda for the environment. Furthermore, the CO_2 emission trading scheme has significant effects. Third, despite international debate, Germany does not have an explicit policy on generation adequacy. The key conclusions are threefold. The initial position of Germany to refrain from regulating network access did not work satisfactorily. The recent creation of regulation can be welcomed and expected to stimulate competition and generation investment. As elsewhere, CO_2 permits are allocated free-of-charge, both for existing and new plants. This may be inefficient, but promotes new investment and thus benefits competition and generation adequacy. The data suggests that new generation investment will be required, but also that the market is active. Apart from wind and CHP, coal seems to have a brighter future than sometimes thought.

1 The authors would like to thank Paul Joskow, Wolfgang Pfaffenberger and Perry Sioshansi for useful comments and remarks.

1 Introduction

The debate on electric power markets seems to be shifting towards the long term perspective: does the market provide timely, adequate and efficient investment? Investment (covering both generation and network assets) affects competition, the environment and supply adequacy. In this contribution we analyse and discuss German energy policy with precisely this focus in mind. Evidently, German energy policy does not stand alone, but rather strongly relies on European policy. The policies we examine are threefold. First, the competition and network regulation of the electric power market, which changed direction in 2005. Whereas Germany initially took an exceptional position within Europe, it is now more in line with neighbouring countries. Second, environmental policy and in particular the start of the CO_2 emission trading scheme deserves attention. Germany has a strong agenda for promoting environmentally-friendly technologies and energy efficiency. The question is how much scope remains for pursuing these objectives. Third, it is noteworthy that there is no policy on generation adequacy; in the light of experience and growing concern in other countries the question is whether this is justifiable.

The capacity margins are now declining but still comfortable, stemming as they do from excess generation capacity before liberalisation. Investment levels have been picking up again in the last two years after a serious decline in the previous five years which followed on from an all-time high as a result of modernizing the former east following re-unification in 1990. This may reflect better competitive opportunities indicated by higher wholesale prices. More worrying is that generation assets are old and need to be replaced, while it is unclear what should replace these. The share of coal and lignite in the generation mix is already large. The CO_2 reductions required by the Kyoto protocol raise doubt about the future of coal. The share of nuclear is already 30% and is being phased out, while new build lacks support. Support for renewables is strong but it is unclear whether this has sufficient scope.

Our key conclusions are also threefold. The initial exceptional position of Germany to refrain from (ex-ante, sector-specific) regulating network access did not work satisfactorily. Clearly, the institutions were not in equilibrium. The recent creation of a regulator (the *Bundesnetzagentur*) and regulation (with the new Energy Act of July 13, 2005) can only be welcomed. For a variety of reasons, network regulation must be expected to promote competition and thereby stimulate new investment by newcomers. We note that the wholesale margin increases.

As elsewhere, CO_2 permits are allocated free-of-charge (instead of auctioned), both for existing plants as well as for new investment. Evidently this has a political background and cannot be supported on economic grounds. Still, a free-of-charge allocation does promote new investment, and thus it may be inefficient, but benefits competition and generation adequacy. A curiosity is the so-called transfer rule which grants new (CO_2 poor) plant the number CO_2 permits of the CO_2 rich plant it replaces. This is good for the environment, but sets new entrants at a serious disadvantage.

With respect to generation adequacy (taking into account the points made above), we note that data suggests that new investment is required, but also that (as elsewhere) there appears to be a lot of new construction plans. Apart from wind and CHP, new coal seems to have, perhaps surprisingly, a brighter future than sometimes thought.

The organisation of this contribution is as follows. Section 2 provides an overview of the recent history and the current state of the German electricity supply industry (ESI). Section 3 gives an in-depth examination of various energy policies distinguishing between the Energy Act, environment policies and generation adequacy. Section 3 includes analysis of the investment effects. Section 4 is the conclusion.

2 The German electricity supply industry

2.1 How the sector is structured

With a population of 82 million, Germany has the largest power market in Europe. Total net electricity consumption is around 500 TWh/yr; installed gross capacity is around 140 GW including more than 15 GW wind capacity – more than any other country in absolute terms. Peak load in 2004 was at 77.2 GW. Total gross revenues in the sector are roughly € 60bn/yr and investment amounts to around € 4bn/yr.

Germany's transmission network is integrated with that of 9 neighbouring countries. Imports and exports are more or less balanced, with a total of 44 TWh imports and 51 TWh exports in 2004. The exchange with France, the Netherlands and the Austrian and Swiss hydro systems is especially significant (see Table 1).

Table 1: German power imports and exports (in TWh)

	imports 2004	exports 2004	imports 2003	exports 2003
Austria	4.4	8.9	3.3	9.9
Switzerland	2.8	11.8	3.1	13.2
France	15.5	0.4	20.2	0.2
Luxembourg	0.8	4.9	0.8	5.0
Netherlands	0.6	17.3	0.6	15.0
Denmark	5.3	3.4	4.0	5.4
Czech Republic	13.1	0.1	12.8	0.1
Poland	0.4	3.2	0.3	2.8
Sweden	1.3	1.5	0.6	2.2
Total	**44.2**	**51.5**	**45.7**	**53.8**

Source: VDN

The main energy source for power generation is coal, which accounts for around 50% of electricity production, with hard coal and lignite each accounting for about half of this (Figure 1). Germany has substantial domestic coal reserves. Yet German hard coal is about three to four times as expensive as imported coal and relies on state subsidies. Since the number of miners has become too small to be a serious interest group[2] and the hard coal subsidy is a state aid and is for this reason not favoured by the EU commission[3], the subsidy is gradually reduced. This will not influence the generation mix or investment decisions, which are based on the price of imported coal, but will reduce domestic coal consumption and increase coal imports.

Lignite is the only other major domestic energy source in Germany. As it can be accessed through open-cast mines, it is relatively cheap and does not require state subsidies[4]. The downside is that open-cast mines consume vast chunks of land, leading to significant public opposition. The RWE utility in the West and Vattenfall utilityin the East are the main lignite producers and generators. While there was a major overhaul of plants in Eastern Germany after reunification, RWE operates a much older fleet of lignite plants, with quite a few plants approaching their 50th anniversary.

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[2] In 2003, there were just over 50,000 people working in hard coal mining and processing and around 15,000 in lignite. The number of employees is bound to decrease further.

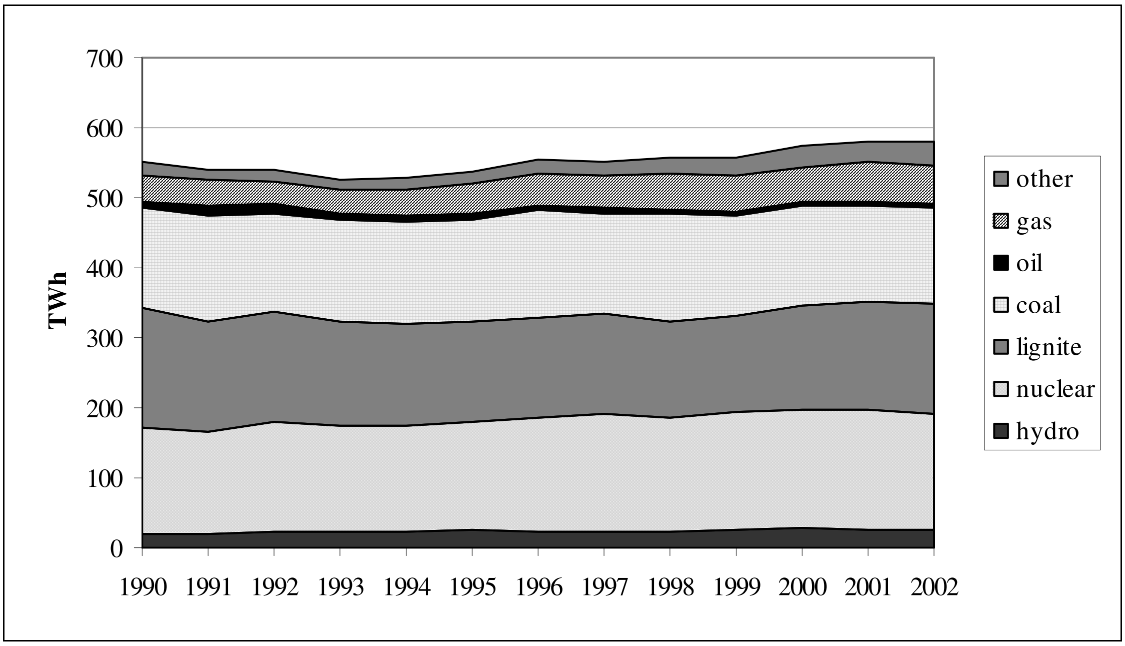
[3] Cf. EU Regulation, No. 1407/2002; July 23, 2002.

[4] There are no official and explicit subisdies, yet it can be argued that there is hidden financial support (Wuppertal Institut, 2004).

Nuclear plants generate about one third of the total power production. However, the red-green government coalition agreed on a nuclear phase-out program which was laid down in the 2001 amendment of the nuclear law. The agreement stipulates a generation limit based on a 32-year plant operation, which means that nuclear generation will be phased-out at around 2020 according to this plan. However, companies have the option to shift generation allowances between plants to increase the output in more efficient plants. In mid 2005, only two plants – Stade and Obrigheim – were closed. The Conservative party has announced that it wants to do away with this agreement and extend the plants' life time. However, with the likely new conservative-socialist coalition it is unclear what will happen.

There has been no 'dash for gas' yet, with gas still accounting for only around 10% of power generation. There are only a few CCGT plants. With only minor domestic gas supplies and a high dependency on gas imports, mainly from Russia, the Netherlands and Norway, there is some concern that an increasing share of gas may undermine supply security. Despite this, generation from gas is forecasted to increase in most scenarios. For instance, a report for the Ministry of Economics [BMWA, 2005, p. 33] projects a share of gas of about 33% by 2030.

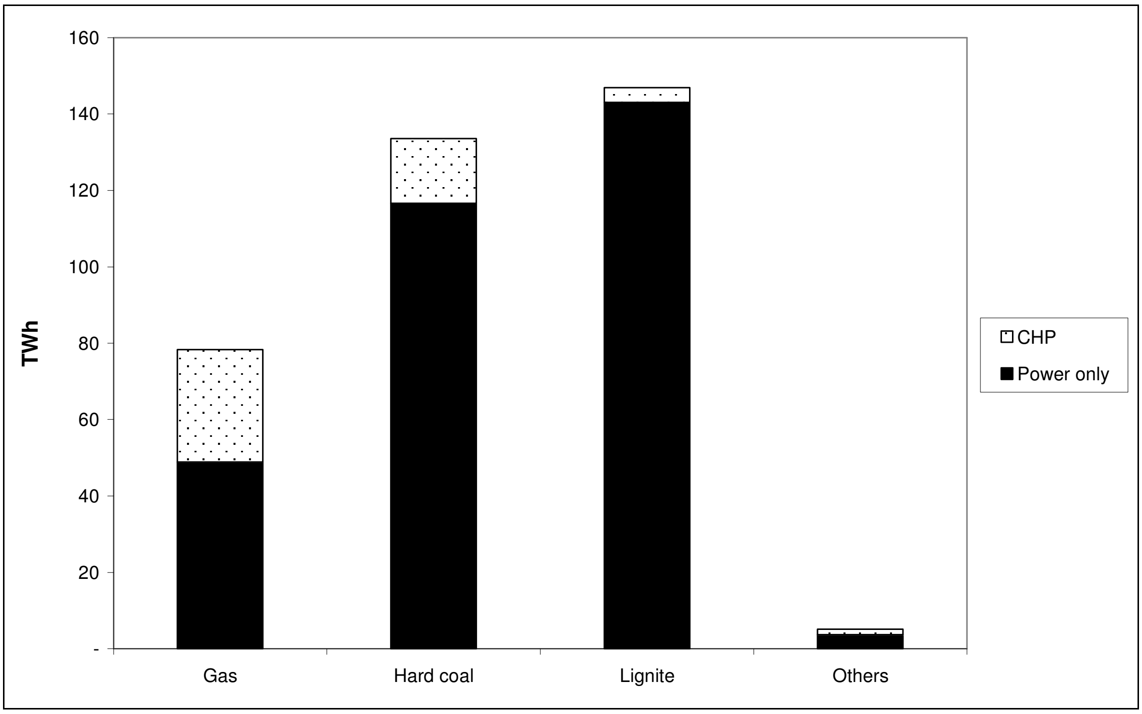
Figure 1: Generation mix



Source: Brunekreeft & Twelemann, 2005

The remaining power is generated from hydro plants and a rapidly increasing share of 'new' renewables, especially wind. The above mentioned report for the Ministry of Economics also projects a share of about 33% for renewables in 2030. Demand growth is relatively low at around 1 % per year and is expected to remain at this level[5]. Combined Heat and Power has a production share of about 10%[6], of which 60% is gas fuelled and 40% hard coal (and lignite) fuelled (Figure 2). There are no official statistics on distributed generation, but the generation share is reported to be at around 18% [Wade, 2005].

Figure 2: Combined-Heat-and-Power Generation



Source: Destatis

Not including industrial plants

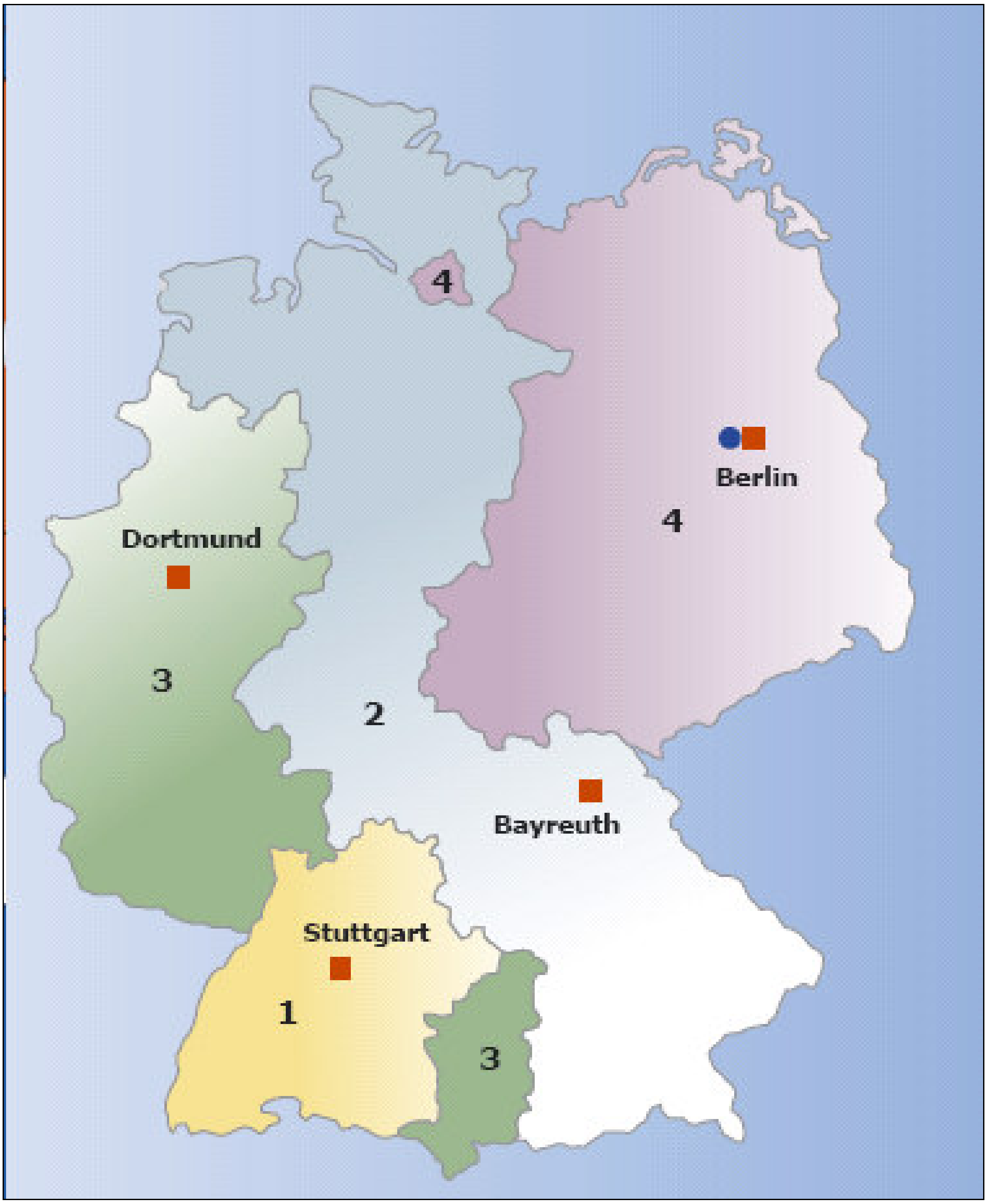
Implementing the EU Directive of 1996, the German ESI was liberalized in 1998 with the Energy Act of 1998. The sector was never institutionally monopolized (like for instance the UK). Instead competition in a relatively unconcentrated and fragmented industry was excluded by cartels agreements, which were stabilized by legally enforced demarcation contracts. The main step of liberalization was to invalidate these cartel

[5] Source: VDEW (www.strom.de)

[6] This does not include industrial plants, which are often CHP plants.

agreements after which the ESI fell under the authority of the Cartel Office and the Competition Act.

Figure 3: **German Transmission System Operators**



Source: VDN

1: EnBW Transportnetze AG; 2 E.ON Netz GmbH; 3 RWE Transportnetz Strom GmbH; 4 Vattenfall Europe Transmission GmbH

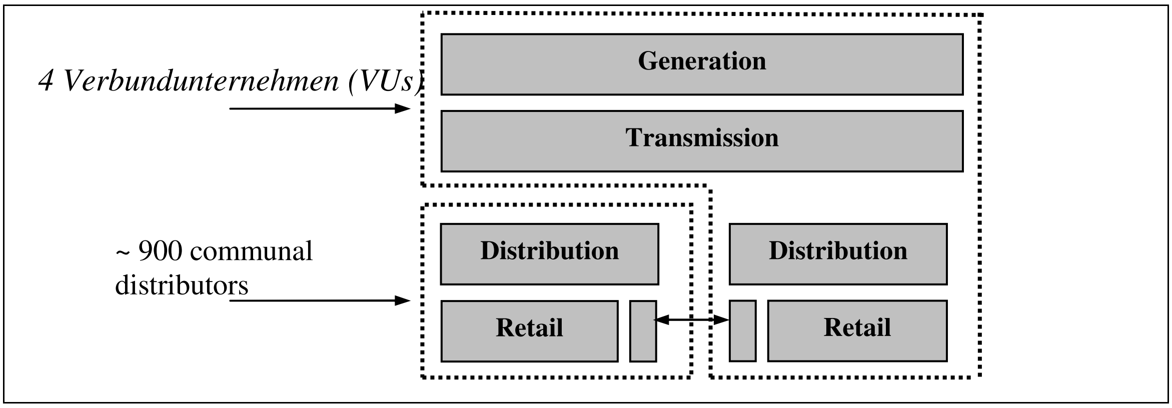
The industry structure, which was artificially stabilized by the demarcation contracts, strongly reflected historical institutional lines; roughly speaking, generation and transmission reflected the position of the states within the federal structure of Germany, while distribution and retail reflected the strong position of the communities. Not surprisingly and as we have seen elsewhere, competitive pressure and commercial interests enforced significant changes in the industry structure after liberalization, most notably towards more concentration. Vertically, the ESI was strongly integrated between networks and commercial businesses and if anything this has increased since liberalization; it is thus remarkable that the Energy Act of 1998 only required minimal vertical unbundling requirements. We will discuss this in more detail below.

The German ESI is strongly vertically integrated. There are basically two blocks, which is depicted in Figure 4. On the one hand, four predominantly privately-owned big utilities own and operate the high-voltage transmission grids (plus the interconnectors) and most of the power plants (usually in their own control area). These firms are both Transmission System Operators (the TSOs) and dominant generators. They operate the balancing market in their own control area. There is an ongoing discussion about separating these balancing markets and merging them into a national balancing market. Together these four companies own about 90% of total generation capacity (Table 2). Moreover, they also have majority shares in many distribution networks and retail activities. These four utilities are RWE, E.On, EnBW and Vattenfall Europe.

On the other hand, a vast number of predominantly municipality-owned firms (*Stadtwerke*) own and operate the distribution networks and, as end-user switching away from the incumbent retailer has been low, mostly the retail activities in the subsequent host areas.[7] As we will argue below, and as also noted by Haas et.al. [2005] the high degree of vertical integration led to cross-subsidization between networks and generation, stifling competition.

[7] The exact number is unclear. VDN, the association of network operators, has 390 members. Also, VDN lists in its publication of network charges 700 different networks some of which fall under the same holding though. VDEW, another industry association mentions 900 firms.

Figure 4: A stylized representation of the ESI in Germany



Most of the municipal utilities were considered to be too small and expected to disappear quickly after liberalisation. However, most of them have done much better than expected, setting up various alliances to defend their market position and to be able to take part in wholesale trading and realise economies of scale, for example in billing. The vertically integrated 'Stadtwerke' also responded to market opening by lowering the retail margins (being the difference between the end-user price and network charge plus wholesale price), making life for new third-party retailers difficult. Cumulative domestic switching rates are reported to be 5%.

Mergers and acquisitions have increased concentration in generation since the beginning of liberalization (see Table 2). Around 2000, two big mergers, creating the current firms RWE and E.On, pushed the Hirschman-Herfindahl Index to more than 2500.[8]

2.2 The institutional steps

Germany implemented the 1996 EU Electricity Directive with the Energy Act of 1998, of which three aspects stood out. First, full market opening. For generation this is unsurprising, but 100% end-user eligibility from the start was exceptional in 1998. Even early 2005, only 9 European Member States had full retail market opening. And although the EU E-Directive 2003 aims at full retail market opening by 2007, we expect that there will be a debate on whether this will be pursued. Full retail competition in Germany worked well technically, but competition developed only slowly for domestic and small commercial end-users. Second, whilst the degree of vertical integration of monopolistic networks and commercial businesses is high and increasing, the rules on unbundling were weak and were not enforced. Third, being the exception within Europe, Germany opted for negotiated Third Party Access, instead of regulated Third Party Access.[9]

Table 2: Market shares in generation (percentages of output)

		1994 A	1994 B	2000 Pre A	2000 Pre B	2000 Post
VEBA	} E.ON	16.92	13.96	21.36	18.77	} 28.74
VIAG		11.23	8.27	12.55	9.97	
RWE	} RWE	31.38	28.42	31.53	28.94	} 37.27
VEW		7.24	6.65	8.84	8.33	
EVS	} EnBW	4.89	4.30	} 9.64	} 8.60	} 8.60
Badenwerk		4.91	4.32			
HEW		3.55	2.96	3.09	2.57	
BEWAG	} V'FALL	2.87	2.28	2.65	2.13	} 15.03
VEAG		-	11.84	-	10.33	
Other		17.00	17.00	10.35	10.35	10.35
Total		100	100	100	100	100
HHI		1807	1595	1903	1658	2622

Source: Brunekreeft & Twelemann. 2005, p. 103.

Note: The shares have been corrected for participation rates. Pre means Pre-merger and Post means Post-merger. V'Fall is Vattenfall

Negotiated TPA implied that, despite the monopolistic networks, the sector was left without sector-specific regulation and regulator. The government trusted the ESI to resolve network access and network charges by voluntary negotiations controlled by the Cartel Office. Network access had to be arranged collectively in the so-called association agreements (VV). Initially, these arranged the (technical and administrative) rules but not the price of network access. Later, a set of accounting principles to calculate the network access charges was added to the VV. At no stage though was the precise level of network charges agreed upon or laid down. These were the sole responsibility of the individual network owners.

[8] In European merger control a post-merger HHI of 2000 and in the USA of 1800 are crucial thresholds. Note however that these are very rough indications, which neglect many details.

[9] Cf. Haas et.al. [2005] for a European overview. Moreover, Brunekreeft [2003, pp. 208 ff.] contemplates on possible explanations for this exceptional position; it is rather likely that the re-unification in 1990 contributes to an explanation.

Both the network access and the network charges were controlled by the Cartel Office. To facilitate this task, the Competition Act was strengthened with an essential facilities doctrine in 1998, which requires that access to the network should be provided on non-discriminatory terms *and* at a fair and reasonable charge. This one clause in the Competition Act was the main regulatory instrument.[10]

Control was not strong and network charges were (and in fact still are) persistently high. The Cartel Office faced a number of problems [Bundeskartellamt, 2001]. First, it is allowed to act only after a justified suspicion of abuse; hence, it can act only ex post. Second, with up to 900 networks to be controlled, the Cartel Office was seriously understaffed for this task. Third, many of communal and regional networks enjoy political support from the states and communities. Fourth, the Competition Act is well suited to address discriminatory behaviour; the more persistent problem however turned out to be the high level of the network charges, which is difficult to address with the Competition Act. Lastly, accounting according to the association agreement received legal validity, which in practice weakened the position of the Cartel Office.

After a series of events and reports, the so-called Monitoring Report of the Ministry of Economics paved the way to stronger regulation in 2003. Parallel to this, the German government gave up its resistance in Brussels and the European Commission seized the opportunity to remove negotiated TPA from the directive. Hence, the new EU E-Directive 2003 exclusively allows regulated TPA. This is also the key development which led to the new Energy Act which entered into force on 13 July 2005.

2.3 Past, present and future

Figure 5 plots an interesting development. Shortly after liberalisation end–user prices (net of taxes) fell strongly, but started rising again shortly afterwards and quite steeply since a year or so.[11] The figure depicts the representative domestic user of Eurostat and relies on Eurostat data. This implies that it only captures the non-switching part of the market, which are still under the old tariff regime. It does not capture the prices of the competitors and thus the prices for switching end-users. As shown elsewhere [Brunekreeft, 2003, p. 220], the best-practice alternative offers undercut the incumbent

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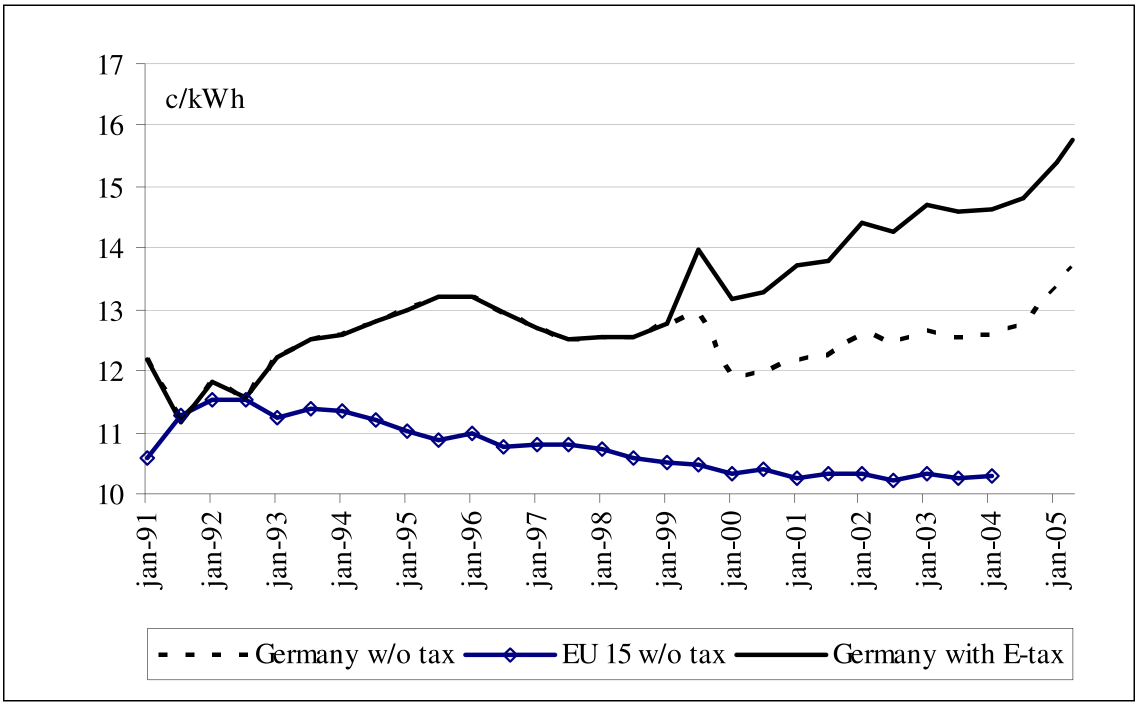
[10] This is not unlike the situation in the USA under the Energy Policy Act 1992. Order 888 of 1996 made a strong move towards regulation of network charges [cf. Joskow, 2005a].

[11] Cf. also Growitsch & Müsgens [2005] for more details.

price severely at first, but then started to increase and converge. Meanwhile the difference is small. Further we should remark that the domestic market excludes the industrial users. The pattern for industrial prices is the same but far more dramatic. Industrial prices have fallen severely but are now increasing steeply as well.

Figure 5: Residential end-user prices in Germany and Europe-15



Source: Eurostat data, various years

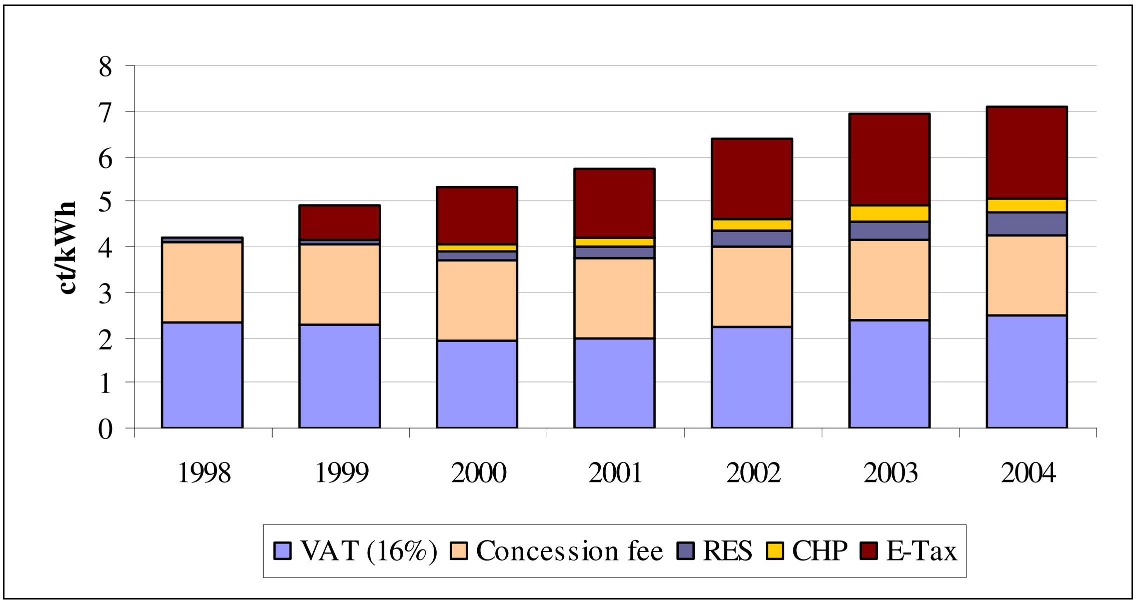
Note: this is for an average domestic end user; eurocent/kWh. Nominal prices.

A steady increase of the electricity tax is an important contributor to higher prices. It has been raised gradually over the last six years to up to 2.05 €cents per kWh, which makes up somewhat more than 11% of the total price. Further substantial parts are the communal concession fee and the federal value added tax; however, these are stable and do not explain the increase. While these taxes are substantial, they are unambiguous. More ambiguous are two levies induced by support for Combined Heat and Power (CHP)[12] and Renewables (RES)[13]. These are not strictly speaking taxes, but the costs of CHP and RES are socialized over network-users and electricity-consumers respectively. It is clear from Figure 6 that whereas these costs are increasing steeply in relative terms,

12 Combined Heat and Power
13 Renewable Energies

they are unsubstantial in absolute terms. Yet, the industry sometimes justifies the price increases, especially the increased network charges, with these ‘tax’ increases.

Figure 6: Taxes in the German electricity price.



Source: VDEW

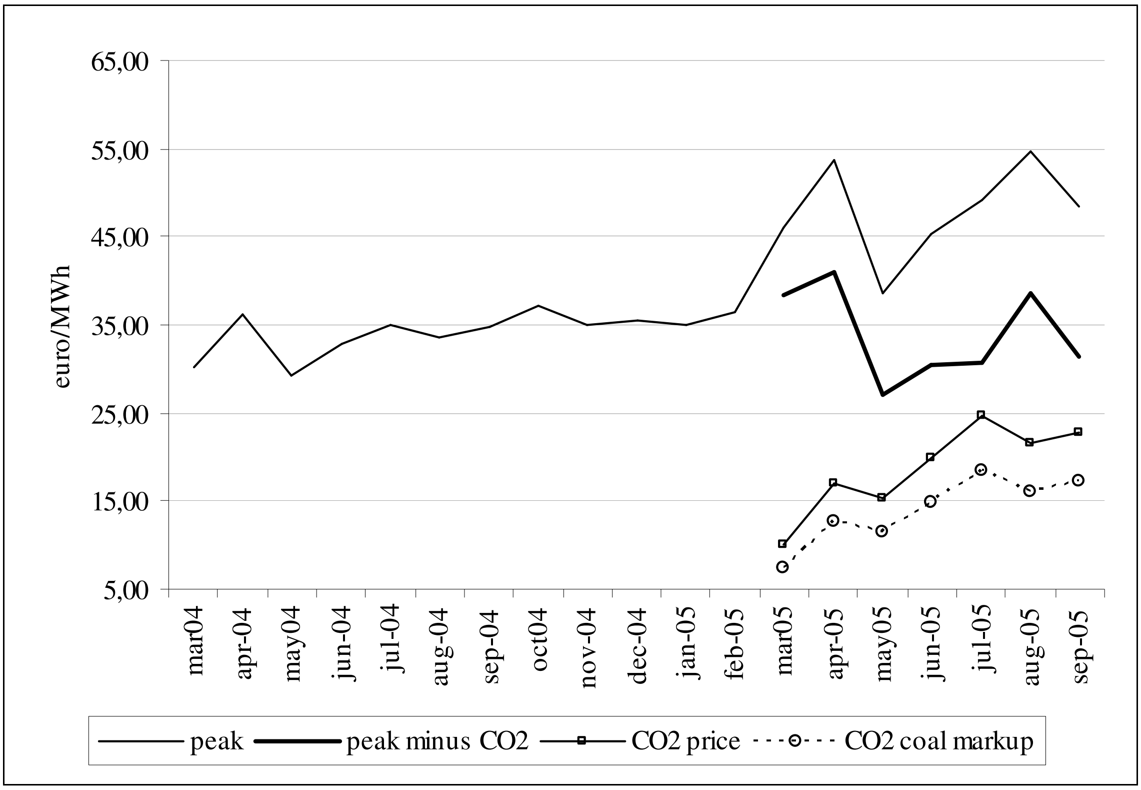
The development of the network charges is ambiguous. Up to mid-2005 the network charges were unregulated. At best, one could argue that rather loose self-regulation was enforced by either some threat of ex-post control by the cartel office, or by the threat of a change towards ex-ante regulation, which indeed happened in mid-2005. In the course of self-regulation the association of network operators (VDN) started to publish a standard format of a sample of network charges for different voltage levels twice a year. Examination of the LV network charges reveals that they were high in international comparison [cf. e.g. EC, 2005] and high relative to end-user prices [cf. Brunekreeft, 2002]. However, they have been stable since at least 2002. Only the HV-level has seen an increase of about 10% which is unsubstantial in absolute terms. According to the network operators, this increase is just the cost-pass-through of higher balancing costs due to an increase in intermittent RES generation. A study of the association of industrial users, VIK[14] suggests a recent increase in the network charges for industrial customers for selected networks. It is unclear whether the changes are representative for the sector. Growitsch & Wein [2004] calculate a reduction of the

[14] Cf. www.vik-online.de, April 28, 2005.

spread in network charges among various operators as a result of the introduction of the self-regulation in VV II+[15]. This suggests that the increases by some are levelled out by decreases by others. All things considered, we should conclude that the recent increase in end-user prices cannot be explained by changes in network charges.

Much of the recent price increase can be explained by the wholesale price development. We note that more than 90% is traded 'over the counter', for which we do not know the prices. However, we assume that the spot price at the European Energy Exchange (EEX) in Leipzig is a sufficiently good indicator for contract prices. Figure 7 gives the EEX price development and clearly shows that the price is rising.

Figure 7: Wholesale prices and CO_2 mark-up at EEX



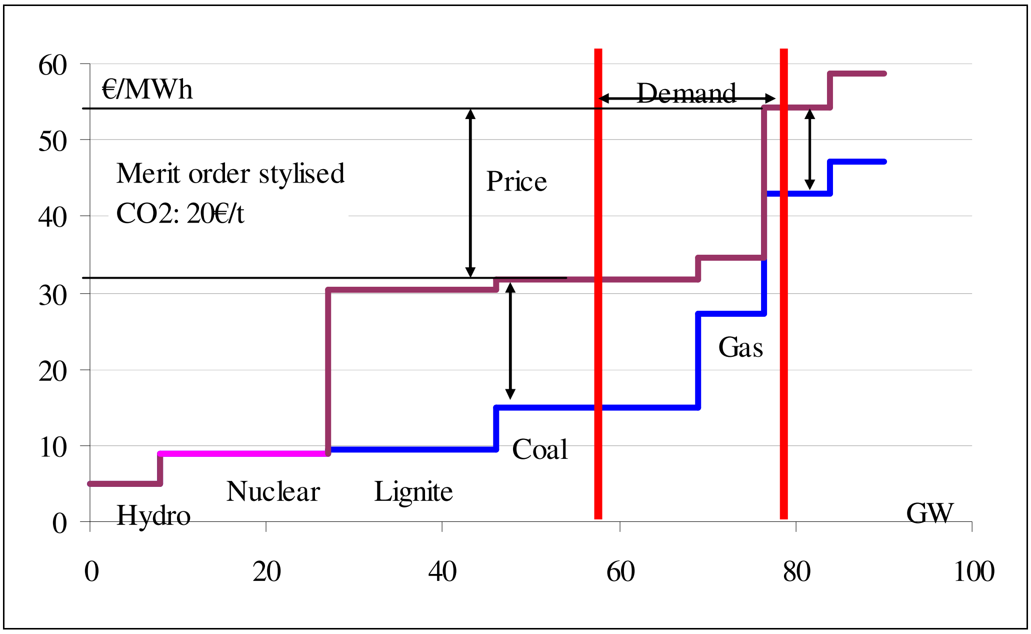
Source: EEX

The wholesale prices used to be very low. In fact, after liberalisation the prices went down to almost short-run marginal costs and could not recover total costs. This is changing. With well over € 35/MWh, it is believed that full cost recovery has been restored. Why the recent increase? There are three plausible explanations.

[15] VV abbreviates the German word *Verbaendevereinbarung*.

First, with the start of emission trading (see below) the electricity wholesale price now includes a CO_2 mark-up. With a CO_2-price of € 20/tonne CO_2 and an emission factor for a coal plant of 0.75t/MWh, this amounts to a mark-up of €15/MWh on the wholesale electricity price. If gas is marginal, then the mark-up is about € 7/MWh because the emission factor of gas plants is about 0.35. If generation is reasonably competitive then the CO_2 mark-up would by and large be passed through into the EEX price. In either case, the effect of CO_2 prices is substantial, as shown for real values in Figure 8. More importantly, Figure 7 suggests that if the CO_2 mark-up is subtracted the net wholesale price fluctuates around €35/MWh, which corresponds by and large to the prices in 2004.

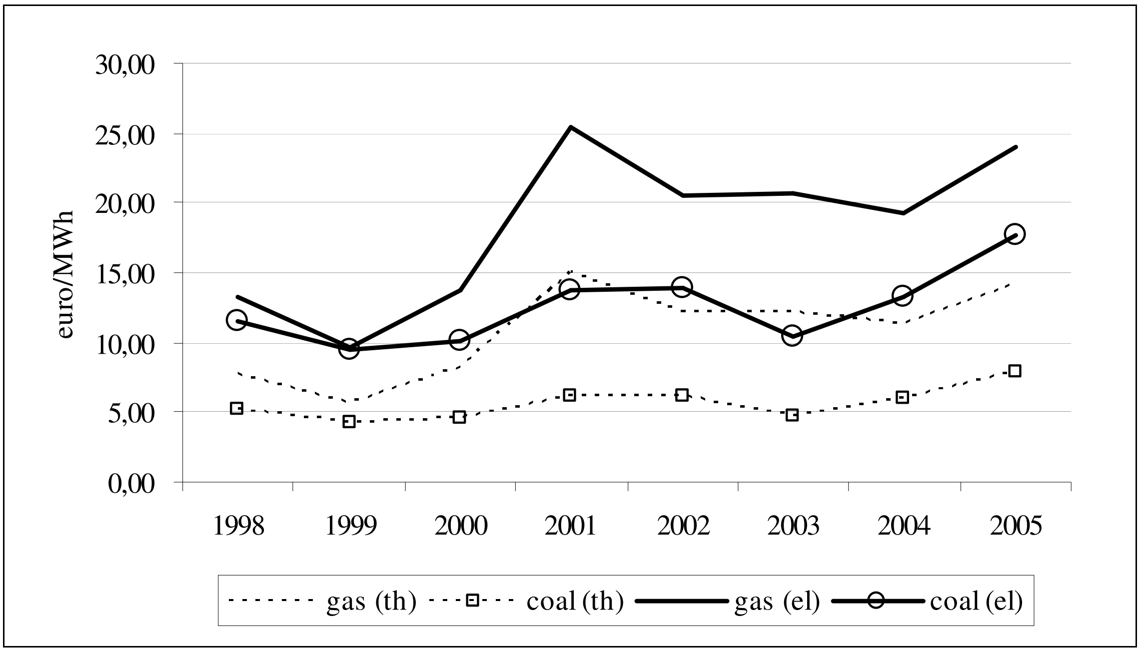
Figure 8: The merit order and subsequent marginal prices in Germany with a CO_2 price of €20/tCO_2



Source: Bremer Energie Institut (this was handed to the authors by Wolfgang Pfaffenberger)

Second, the fuel prices have increased as depicted in Figure 9. For Germany the increase in gas and oil prices has less influence on wholesale prices because gas is not often marginal, but the world coal price has increased recently as well.

Figure 9: Price development of gas and coal



Source: BAFA (efficiency gas: 59%, coal: 45%)

Third, for different reasons, the price increase may reflect a stronger control of the producers on the market, which at the very least seems to ease competitive pressure. Using an elaborate electricity market model, Müsgens [2004] makes an in-depth examination of costs, bidding and prices in the period from 2000 to mid-2003. He finds a structural break in early 2002. Before that prices were closely in line with system marginal costs, while from then on prices started to diverge from system marginal costs. Notably, the divergence is mostly in high demand periods. It does not follow though that these prices are excessive; as already noted, the early prices were too low to recover costs, whereas after early-2002, they might just recover full cost.

Why would prices start to diverge from system marginal costs? Arguably, installed capacity in Germany was excessive, which was likely to increase competitive pressure and suppressed prices down to short run marginal costs. Around 2000, the two big players, E.On and RWE announced that they would shut down some 10 GW of plant capacity because prices were too low; part of this was decommissioned and part mothballed. In addition to other reasons a decline of excess capacity and the resulting relative scarcity are likely to have given the firms some grip on the prices.[16] Alternatively, the higher prices might simply reflect emerging scarcity and actually

[16] In formal terms, mothballing capacity can be interpreted as a credible commitment not to use this capacity and it can thereby ease competitive pressure.

signal that new investment is needed. Further, as shown in Table 2, concentration has increased around 2000 with the RWE-VEW (now RWE) and VEBA-VIAG (now E.On) mergers. With the HHI increasing from 1700 to 2600, theoretical insight and experience abroad would suggest a potential weakening of competitive pressure, as also suggested by Haas et.al. [2005]. Cross-border trade will certainly increase competitive pressure, but this is still limited. Table 1 shows that Germany is a net exporter, mainly because the prices in the Netherlands are higher than in Germany. Furthermore, cross-border capacity is only some 14% of total installed capacity. We would like to stress though that current wholesale prices (less of the CO_2 mark up) do not seem to establish an *abuse* of market power.[17]

Lastly, in 2001 a report of the Cartel Office made clear that network charges were high [Bundeskartellamt, 2001]. As a result the industry attempted to strengthen industrial self-regulation and started to publish the network charges systematically and in a comparable way. Pressure to regulate network access and network charges started to increase. The EU E-Directive 2003 removed negotiated TPA altogether and required regulation, which has now taken shape in Germany (see below). As argued extensively in Brunekreeft [2002 and 2004], given vertical integration and the lack of effective regulation of network revenues, the rational strategy was to concentrate on the network while keeping the margins in the competitive businesses low and thereby retaining market shares. As regulation of the network takes shape we would expect the reverse, i.e. an increase in both the wholesale and retail margins.

The implications for new entry and investment follow swiftly. After the German market was liberalised in 1998, foreign companies showed especial interest in entering the German market. Although the German generation market was by far not as attractive as for example the Spanish or Italien markets in terms of wholesale price, the need for additional capacity or expected demand growth, many companies considered it strategically important to be present in the largest European electricity market. The large number of small and medium-sized utilities provided good take-over candidates.

It took only a few years for this excitement to die down. This was partly because many new players like Enron or Dynegy either completely disappeared or were on the brink of disappearing. More importantly, the German market turned out to be hostile

[17] This leaves the question open what exactly is market power and how prices above marginal costs can be stable in a competitive environment.

towards new entry for a number of reasons. First, it was difficult to get hold of new plant sites. Second, as indicated above, wholesale prices were unattractively low. Third, in the first few years after liberalisation the arrangements on network access were biased against third parties. Fourth, there have been persistent complaints about discrimination of third parties. Fifth, as far as new entry from gas-fuelled CCGT is concerned, the big electricity-gas merger E.On-Ruhrgas (controversially approved in 2002) did not improve competitive conditions. Sixth, a gas tax represented a significant entry barrier for new gas plants. The gas tax increased the costs of a new CCGT plant by ca. 3 €/MWh or 10%. There were limited exemptions from the tax for new CCGT plants with an efficiency of more than 57.5%. Following a new European directive on energy taxation[18], this tax was abolished in 2005.

Many new plant projects were either given up or had to look for new investors who were willing to keep these projects alive and wait for better times. New firms entered the market mainly through acquisitions; for instance EdF bought a minority stake in EnBW and Vattenfall took over Bewag, HEW and VEAG. This did not always improve competition, but rather increased the concentration in the wholesale market. While Germany has not seen many new plant projects that actually came on-line since market opening, investment activity is now picking up again as we will indicate in section 3.3. The wider wholesale margin is definitely helpful in this respect.

3 Energy policies and the investment effect

Before discussing energy policies in Germany in detail, Table 3 gives an overview of the main acts and events as they affect the ESI.

3.1 The Energy Act 2005, regulation and the regulator BNA

3.1.1 The Energy Act 2005

As explained above, for a variety of reasons, the Energy Act 1998 was replaced by the Energy Act 2005, with the following key elements. First, the approach of ex-ante approval of the methodology and ex-post control of the level did not survive the debate, and a clear step has been taken towards ex-ante regulation of the network charges. Second, although starting off with a cost-based approach, it is an explicit intention of the authorities to switch to incentive-based regulation. Third, there will be a sector-

[18] Directive 2003/96/EG

specific regulator: the *Bundesnetzagentur* (BNA). Fourth, the rules on unbundling are strengthened but they still only minimally fulfil the Directive's requirements..[19]

Table 3: Major Events in the German Electricity Supply Industry

Date	Event	Comments
April 1998	Amendment Energy Act, Start of liberalisation	100% market opening in generation and supply
May 1998	First Assocation Agreement VVI	Self-regulation of networks
April 1999	Introduction of the electricity tax	Starting with 1.02 c/kWh and gradually increased to 2.05 c/kWh.
December 1999	Second Assocation Agreement VVII	New retailers (eg. Yello) enter the market; prices drop severely and surprisingly, but only short-lived.
April 2000	Renewable Energy Act	Fixed feed-in tariffs for renewables
August 2000	European Energy Exchange in Frankfurt	
December 2001	New Nuclear Act	Stipulates phase-out of nuclear plants in Germany, prohibits new nuclear plants
April 2001	Report of the federal Cartel Office	Indicates that network charges are high and difficult to control by Cartel Office by Competition Act.
December 2001	Third Assocation Agreement VVII+	Stronger emphasis on industrial self-regulation
2000/1	Mergers:	- RWE and VEW: RWE - VIAG and VEBA: E.On
2002	Merger:	E.On and Ruhrgas
December 2003	Monitoring-report by the Ministry of Economics	This report confirms 'officially' that negotiated TPA in the ESI and GSI failed. It paves the way to regulated TPA.
January 2005	Emission Trading starts	
July 2005	Amendment of Energy Act,	implementing EU directive, ending seven years of self-regulation of the network Regulator (*BNA*) takes over electricity network regulation

[19] Haas et al [2005] are somewhat sceptical about the new Energy Act and point out that the legislator might have taken the opportunity to put in place a more pro-competitive market design.

Ex-ante regulation of the network charges.

Art. 23(2) of the EU E-Directive 2003 requires "fixing or approving, prior to their entry into force, at least the methodologies used to calculate" the network charges. The precise phrasing reflects the German wish to stick to ex post control of the level of the charges. In fact, this type of ex-ante/ex-post hybrid regulation has been practiced in, for instance, Sweden (with mixed success) and Finland (where it worked well). After a long debate, it has been decided in Germany that the by-pass in the Directive be ignored and the ex-ante regulation of the level of the access charges be applied. Thereby the regulation of the network access charges is finally as it should be.[20]

There has been some debate about controlling price *increases* only. This would imply that all current levels would be beyond the authority of the regulator. Since some network operators have increased their charges quite significantly over the last year (i.e. before regulation would take effect), this restriction in regulatory authority was unacceptable and was overthrown. The regulator has now been authorized to look back and control the recent price increases.

Cost-based versus incentive-based regulation

The main debate has been on the type of regulation. The formal current state is that regulation is cost based (par. 21), which reflects business as usual. Previously, the 'self-regulation' followed the accounting principles laid down in the association agreement. This is nothing else than a rate-of-return regulation, with the difference that it will now be enforced and resulting charges will have to approved before they enter into force.[21]

The legislator explicitly allows the option to switch to incentive-based regulation (par. 21a), which can be a price-cap or revenue-cap regulation. The regulator has been given the task to develop an incentive-regulation mechanism. However, whether, how and when this will be implemented is to be determined by the government in an ordinance (i.e. not by the regulator).[22]

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[20] Increases of domestic end-user prices required approval of state authorities relying on a federal decree. The enforcement of this decree has always been questioned. In any case, as a result of the new regulation of the network charges, this decree on end-user prices will expire in mid-2007.

[21] The interested reader may refer to Brunekreeft & Twelemann [2005, p. 109] for details. The new Energy Act is a step away from the controversial accounting of replacement value. Presumably the practical background is that replacement value can lead to a high RAB whereas the network may have completely depreciated.

[22] It may be noted as an aside that the policy uncertainty is striking: it is, at best, likely that regulation will be incentive-based in the future, but we do not know when or what it will look like. This may be compared to Norwegian legislation where the switch to incentive-based regulation in 1997 was laid down in 1991 in the law.

The choice between cost-based and incentive-based regulation deserves attention. Incentive-based regulation aims at improving the incentives of the regulated firm to produce efficiently (i.e. cut costs). The means to do so is to allow the firm to keep the profits resulting from efficiency improvements. Not having to lower the (ex ante allowed) prices after lowering costs for some predetermined period is the incentive. The German Energy Act explicitly mentions incentive-based regulation, but as has been pointed out by Joskow [1989 and 2005b], it is not so clear what this means and how incentive-based differs from cost-based regulation.[23] Three points seem important.

The name rate of return regulation (being a typical form of cost-based regulation) suggests that prices should always be adjusted to costs so as to allow a reasonable rate of return. In practice this is not the case as rate-of-return regulation typically also fixes (weighted average) prices for some period of time: the regulatory lag. During this period prices can deviate from the 'fair' rate of return. The difference in emphasis is that under typical cost-based regulation the regulatory lag is endogenous and relatively short. As Joskow [1974] explains well, typically in the USA, (weighted average) prices remained fixed until either the firm or the regulator requested a rate hearing. An important innovation of the incentive-based regulation first introduced by Littlechild in 1983 was to make the regulatory lag explicit and exogenous as a closed regulatory contract [cf. Beesley & Littlechild, 1989].

A second point is that a cost-based approach typically adds a mark-up to the firm's *own* costs. This is fair and reasonable but does little for the incentives to keep costs low. An incentive-based approach steps away from this and tries to avoid the use of the firm's own costs as the benchmark. Instead it might use an industry benchmark. This retains the incentives but may lead to unreasonable results. These are theoretical polar cases; in practice the difference is blurred. Typically, with cost-based regulation, the regulator will look at whether the underlying costs are reasonable and thereby use comparators. Also, in incentive-based regulation any regulator will always check whether the outcome for an individual firm is reasonable.

A third point is that pure cost-based or pure incentive-based mechanisms only exist in textbooks. In practice details matter and we find all kinds of adjustments and

[23] To be precise, incentive-based regulation is the overarching term of which pure cost-pass-through and pure price-cap are the polar cases [cf. Joskow, 2005b]. So, it is not really appropriate to contrast cost-based with incentive-based. We will assume that in the Energy Act incentive regulation means a move towards price or revenue capping

modifications and we see that the polar cases converge. Two examples are important. Rate-of-return regulation can be modified by a use-and-useful clause [cf. Joskow, 1989], which basically says that the investment costs may only be passed through in the rate base if the investment is used and useful, on which the regulator decides. Clearly this steps away from pure cost-based regulation. Incentive-based regulation can be adjusted by profit-sharing rules, basically saying that if under the incentives-based constraint profits get either too large or too small, prices can (should) be adjusted. This clearly adds a cost-based element. Illustratively, Grout & Zalewska [2003] define a profit-sharing rule as a weighted average of the outcomes under cost-based and incentive-based regulation.[24]

The Energy Act (para. 21a.2) highlights the ex-ante determination of the average revenue cap as the decisive point. The control period will be between 2 and 5 years. Furthermore, relative efficiency will be determined by benchmarking with comparable firms.[25] It should be noted though that this also holds for the current cost-based approach, where the reasonableness of the firm's *own* costs can be checked by comparing with other firms. Moreover, only the costs components which are under control of the firms will be subject to efficiency incentives.

Although without explicit details, the Act touches upon the following aspects. First, presumably the price-cap regulation will be tariff basket, capping the weighted average price of a basket of products and leaving individual prices to the firms.[26] Second, the regulation will explicitly be quality-adjusted, presumably with a penalty-&-reward system. Third, it seems unlikely that there will be a yardstick; the X_i will be firm-individual or firms will be collected in comparable groups. The discussion on X versus X_i is non-trivial in the face of up to 900 networks. Faced with so many firms, a yardstick X for all is very attractive but seems unreasonable.

Bundesnetzagentur (BNA).

The EU E-Directive 2003 requires with art. 23(1) regulatory authorities, "wholly independent from the interest of the electricity industry." This excludes industrial self-regulation as it was practiced in the German ESI, especially by means of the VVII+.

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24 The distribution price control 2005-2010 in the UK provides interesting examples.

25 There is some discussion to apply a *virtual network approach* as in Sweden to pre-select some very highly priced networks.

26 This stands out against the regulation of telecommunications, which has a stronger leg in the regulation of individual prices.

The new Energy Act creates the sector-specific regulator *Bundesnetzagentur* (BNA), which will include the regulator for gas, telecommunications and postal services and which will also cover railways.

Authority has been split though. The federal regulator BNA is responsible for all network operators with more than 100,000 customers (and for network owners with less than 100,000 customers that operate in more than one state). The states are in charge of regulating smaller network operators. However, if desired, the states can hand over the regulation to the federal BNA[27]. This follows article 15(2) in the EU E-Directive 2003, which exempts network operators with less than 100,000 customers from unbundling rules (except separate accounts). At least 500 networks are the responsibility of the states.[28] Because the communal lobby is very strong and states and municipalities are the main stakeholders in the DNOs, we may expect that state regulation of the DNOs will be weaker than federal regulation.

It seems that all the regulators will have to follow the same federal ordinance concerning the choice of regulation. This is a missed opportunity. As pointed out the idea is to switch to incentive-based regulation. One of the problems is how to manage the regulation of 900, mostly very small DNOs. Exactly this problem could be by-passed by applying different types of regulation: a strict incentive-based regulation at federal level and a 'loose' cost-plus approach at state level for many small utilities. If all the small DNOs are also regulated by the same type of incentive regulation, it is unclear what is gained with splitting up the authority, while it opens the door for regulatory capture at state level.

Unbundling

The unbundling requirements correspond to the EU Directive. Hence, the Energy Act requires legal (and functional and management) separation of TSO and DSO (with the art. 15(2) exemptions as mentioned above), confidentiality of information and accounting separation. This has by and large been implemented. The more urgent point is whether it will be enforced and controlled. As the regulator will pick up its task, we are confident that this will indeed be serious and that firewalls will start to be pressing. The more interesting question is whether ownership unbundling has any prospect. This question is aimed at the TSO in first instance. The legal problem is that the four TSOs

[27] In summer 2005, most states have decided to keep a state regulator.
[28] However, the aggregate market covered by these firms will be small.

are largely in private hands and that ownership unbundling is expropriation and violates the constitution. However, there are signs that ownership unbundling may re-emerge as an issue. First, there is some debate to split off the system operators (SO) from the rest of the firm and thus leave the transmission ownership (TO) to the current owners. This would also allow the creation of both one national SO and one national balancing market. The SO has no assets and this approach would therefore most likely not be regarded as expropriation. Alternatively, all current firms could have the national SO in collective ownership. Second, experience in the UK, for instance, suggests that very strict firewalls can make 'voluntary' unbundling an attractive option for the companies. Typically, this requires very strict monitoring by the 'watchdog' and hence depends a great deal on the BNA.

3.1.2 The institutional disequilibrium

Why did the government decide not to regulate from the beginning of liberalisation? Recall that the German telecommunication sector does have sector-specific regulation by a regulator. Although speculative, four related arguments are apparent. First, the legislator may not have been completely benevolent. The sector's influence on politics is considerable. Second, the energy sector (gas and electricity) is considered to be strategic. Faced with counterparties like Gazprom, the government hesitates to fragment the industry too heavily and tries to balance between different goals (in this case, in particular between competition and countervailing power). Third, there has also been the desire to create and support 'national champions' able to compete on a European scale. Fourth, after re-unification the firms from the West committed to investing heavily in the former East in order to modernize both plants and networks. Oddly, this did not result in stranded-costs claims when liberalization started, unless we should interpret the lack of regulation as such.

In any case, only seven years after liberalisation, the institutional framework was adjusted to adopt ex-ante regulation of the network charges. Hence, we may conclude that the framework was not in equilibrium and that something went wrong.[29]

Changes in the ESI are at least partly a spin-off of the gas supply industry (GSI). The GSI as well as the ESI was supposed to develop an association agreement for network access. Whereas this by and large succeeded for the ESI, this failed in the GSI, leaving the government no option but to intervene. However, as this contribution is on the ESI, we will continue with an examination of the developments in the ESI.[30]

High network charges are against consumers' interests, but as long as they are within a reasonable range they are unlikely to arouse too much political attention. More important is that competition died off after a first wave of excitement. Retail competition for domestic users is problematic. Switching rates are low and third party suppliers are in financial distress. Although consumers perhaps do not switch because they are satisfied with their incumbent supplier and although potential competition may work, we observe that active competition is not a great success. Müller & Wienken [2004] estimate that roughly 40% of the household market is effectively closed, because the margin is below cost.

The developments on the wholesale market were similar and highly remarkable (see above). Undoubtedly there has been quite strong competition, which in the beginning resulted in renegotiation of old contracts by large users (industry and retailers). The presence of competition and traders acted as a threat in the bargaining game. The prices for large users, which are an indicator for wholesale prices, came down strongly, presumably squeezing out the air resulting from productivity increases made in the 1990s and which had not been passed through. As shown in Figure 7 above, wholesale prices at the power exchange in Leipzig were very low; as low as fuel costs and substantially below cost recovery. This short-lived success has depressed entry: the first six or seven years of liberalization have not or have hardly seen third parties in generation and most planned projects were never realised. If anything, firms left the market, while the assets in the market became more concentrated through mergers and acquisitions. The low entry activity reflects different issues. The low wholesale price, policy uncertainty about next institutional steps (regulation or not) and discriminatory behaviour by the network operators will all have contributed to hesitant new entry. As we will discuss in section 3.3, this is now changing.

Weak regulation of a strongly vertically integrated industry (and weak enforcement of unbundling) implied difficult times for competition. Complaints about discrimination against third parties have been persistent. Indeed, the first association

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[29] We have studied this in detail elsewhere [cf. eg. Brunekreeft, 2002 and 2003], and we will summarize it here briefly.

[30] The interested reader may refer to Brunekreeft & Twelemann [2005, section 2.2] and references quoted therein for further details on the GSI.

agreement was most certainly not pro-competitive. Moreover, during the first years after market opening, the Cartel Office has been active to settle unresolved issues and pursue abusive behaviour. Moreover, the institutional framework of vertical integration without effective regulation of the network charges created the incentives for a margin squeeze: in case of doubt, the integrated firms will make (excess) profits on the network, not on the commercial business. The resulting low margins were unattractive for third parties.

Summing up all the points above, we conclude that among other effects, effective regulation will widen the retail and generation margin (i.e. higher wholesale prices) and make abuse of the network or system-operation more difficult. All in all, effective regulation will promote new entry in generation and retail and thereby promote new investment.

3.1.3 Regulation and network investment

Regulation and the choice between cost-based or incentive-based have potentially substantial effects on network investment. Incentive-based may be good for short-run efficiency but may impede long-run network investment. Recall from section 3.1.2 that the difference between cost-based and incentive-based is not clear-cut but rather a gradual matter of accents; the same applies for the reflections below.

It is not implausible that the explicit step of creating regulation and a regulator as already carried out by the Energy Act decreases (policy or regulatory) uncertainty. This can have a stimulating effect on investment. A second effect concerns the institutional choice for the BNA, which is part of the Ministry of Economics. Independence, being one of the leading regulatory principles, is thereby violated. How this could work out depends on the interests of the Ministry. Although it does have stakes, the federal Ministry is not a major shareholder in the power industry; the Ministry's primary interest will be the consumer. This implies that the regulator might be under political pressure to lower the network charges if this is politically opportune.[31]

Other effects concern the choice between cost-based and incentive-based regulation. Though being still ambiguous in an empirical sense, cost-based approaches are seen as inefficient and generally wasteful of resources (gold-plating) and dependent

[31] This contrasts to telecommunications, where the government was the major shareholder of Deutsche Telekom, although its stakes reduced gradually by floating the shares. Furthermore, the situation is in

on details biased towards over-capitalization; this was one of the drivers to move away from cost-based approaches [cf. Beesley & Littlechild, 1989, p.456]. The long-run perspective reverses the argument. Gold-plating may be inefficient but might be good for investment.

Gilbert & Newbery [1994] point out that, in an uncertain world, the expected deviations from the reasonable outcome are smaller under cost-based regulation than under incentive-based regulation. Importantly, this increases the credibility of the regulator to stick to previously announced policies. In other words, incentive-based regulation can impede network investment as it reduces the regulator's credibility.

Peltzman [1976] pointed out the 'buffering hypothesis', which means that rate-of-return regulation reduces the firm's exposure to market risk as compared to no regulation. Wright et.al. [2003] extend the argument for price-cap regulation. In terms of demand uncertainty, risk under the price-cap regulation is lower than without regulation, similar to rate-of-return regulation. In contrast, in terms of cost uncertainty, risk under price-cap regulation is higher than without regulation. The arguments imply that the firm's risk-adjusted cost of capital might be higher under price-cap regulation. All else equal, this means that investment may be lower under price-cap regulation.

Lastly, as Spence [1975] pointed out incentive-based regulation has poor incentives for investing in quality. A price-cap regulated firm can increase profits at the expense of quality. Regulators in the Netherlands, Norway and the UK, for instance, have adjusted the price-cap regulation for quality incentives. The new Energy Act in Germany allows the BNA to make the necessary quality adjustments.

As argued in section 3.1.2, what we would expect is that if long-term network investment becomes more important relative to short-term efficiency, incentive-based regulation will be modified to cost-based type of regulation and quality-adjusted regulation. It appears that this is happening in the UK where the new distribution price controls which came into force in April 2005 included sliding scales and used-and-useful test for capital overspending.

3.2 The policy on renewables, CHP and the CO_2 emission trading scheme

German environment-related policy has the following targets:

contrast to the state level; the states are stakeholders in the power industry, and there we might see the directions go the other way around.

- Under the EU burden sharing agreement to implement the Kyoto climate protocol, Germany has committed itself to reducing its greenhouse gas emissions by 21% between 2008 and 2010, as compared to the 1990/1995 emission levels.
- Combined heat and power (CHP) generation is to play an important role in achieving these targets. In accordance with the national CO_2 reduction strategy the electricity supply industry committed itself to reducing CO_2 emissions through an increase of CHP generation by at least 20 mio. tons by 2010, which would mean nearly a doubling of CHP generation to 20% in 2010 compared to 2002 levels. According to the CHP Act, CO_2 emissions are to be reduced through an increase of CHP generation (10mio. t by 2005; 23mio. t by 2010).
- The red-green government aimed at doubling the share of renewables by 2010 from 5% to 10%.

3.2.1 Support for Renewables and Combined Heat and Power

Renewables (RES) and Combined Heat and Power (CHP) are supported by the Renewable Energy Act (EEG) and the CHP Act respectively. The support mechanisms for EEG and CHP plants are basically a subsidy, although different in detail. While EEG plants get a fixed remuneration depending on technology and plant size, the payment for CHP plants varies with the market price.

CHP in Germany has a production share of 10%, of which 60% is gas- and 40% coal- or lignite-fuelled (Figure 2). Support for CHP is a plain subsidy over and above the market wholesale price. The arrangement is the result of stranded cost compensation, after it turned out that CHP became unprofitable after liberalization. The CHP Act applies only to CHP plants that were in operation when the Act entered into force and will be phased out. The Act does only apply to new plants if they replace exiting plants (modernisation) and for small CHP plants below 2 MW_{el} and fuel cells. As a result, the CHP Act does little for investment which expands CHP capacity.

RES are promoted by the RES Act (EEG), which arranges a feed-in charge system with a take-off obligation: a “take and pay” system. Like the CHP support now, the pre-liberalisation system used to be a predetermined subsidy on the ‘market price’. With liberalisation the market prices and thereby the feed-in charging fell substantially, pushing the RES plants into financial distress and suppressing new investment. The government decided to change the system by fixing the feed-in charges independent of market developments. The feed-in payments are generous, with a minimum payment of €c 5.5/kWh for wind and €c 43.4/kWh for solar. The support mechanism distinguishes between technologies, vintages and sites, thereby increasing overall efficiency.

The costs of the feed-in mechanism are socialized over all end-users. Whilst under the old pre-liberalisation mechanism, each DNO had to bear the total costs of renewables in their area individually, the EEG has established a mechanism whereby the costs are spread country-wide. The distribution network operator (DNO), to which the RES plant is connected, is obliged to take-off the energy, but passes this on to the transmission system operator (TNO) to which it is connected. The TSOs spread the burden equally among themselves and calculate a nationwide compensation charge. They then pass it on proportionally to the suppliers in their region, who in turn pay the compensation charge and pass-through the costs into the end-user price. In 2004, the share of RES was about 9% and the calculated compensation charge 9 €c/kWh; with a wholesale price of 3.3 €c/kWh, this amounts to a 'RES tax' of 0.51 €c/kWh.[32]

A 'take and pay' system of feed-in charges and take-off obligation affects competition only in an indirect fashion. The system implies that RES and conventional sources do not compete directly. Indirectly, the conventional suppliers face reduced residual demand (which is total demand minus the exogenous supply of RES), which brings the price down. Also, we should expect that as the capacity-load-margin increases (excess capacity), competitive pressure increases, which further reduces prices. Moreover, under a system of fixed feed-in charges and take-off obligation the RES do not directly compete with each other. If the share of RES is moderate this is acceptable, but if the share is substantial a large part of the market will effectively be exempted from competition. If the RES share grows, the designs of the market, network regulation and a RES support mechanism might need to be reconsidered.

Network connection charges are shallow, meaning that new generation assets only pay for the cost of connecting to the first network connection point, whereas the costs of network upgrades beyond this connection point are borne by the network operator. The network operators are obliged to connect new plant as long as the request is reasonable and, if necessary, undertake network enforcements. There is a new debate, however, about an estimated € 800m for an HV network upgrade which would be

[32] Compare Haas et.al. [2005] for an overview and impression of European policies and experiences.

necessary to facilitate offshore wind projects. Evidently, the industry argues to pass-through these costs.

Plants connected to the distribution network (distributed generation), including CHP and RES, receive a network charge rebate. The calculation of grid charges is based on the assumption that all electricity is fed into the high-voltage transmission grid. The payment from the distribution network operator (DNO) to the transmission system operator (TSO), however, is based on the actual annual peak load which the DNO gets from the TSO, reduced by a coincidence factor. As a result, if there are plants connected to the distribution network, the payment which the DNO receives from grid users may exceed the charges he has to pass through to the TSO. DG receives these avoided network charges. More generally though, while the support for renewables does lead to more decentralised generation, there is no explicit policy on distributed generation yet.

3.2.2 CO_2 emission trading

Emission trading started at the beginning of 2005, as part of a European-Union-wide emission trading scheme. The first trading period is a pilot phase, lasting until 2007. The second trading period will last from 2008 until 2012. Each EU member state had to draw up a national allocation plan, defining the overall emission targets for the various sectors (macro plan), including the targets for those sectors covered by the ETS (industry, energy), and the method of allocating CO_2 permits to individual plants (micro plan).

The allocation of permits to individual plants is based on two principles: grandfathering based on historical values for existing plants and a kind of benchmarking for new plants. Permits are allocated to existing plants on the basis of historical emissions multiplied by a reduction factor, whereas new plants receive the permits based on their expected emissions with an upper limit set by modern coal plants and a lower limit set by CCGTs. In both cases, permits are allocated free of charge.

How will the allocation plan affect investment in new power plants and thereby the environment, generation adequacy and competition? The leading principle is that *irrespective* of whether the CO_2 permits are auctioned or are free of charge, there is an opportunity cost corresponding to the market price of the permits, pushing up marginal costs. They will thus be passed through into the electricity wholesale price. If the permits are auctioned then evidently they are real (variable) costs. If the firms receive the permits free-of-charge they earn windfall profits equal to the quantity of permits times the price.

The more relevant effect is on new investment. The CO_2 price as such has a merit-order effect: it makes gas less expensive compared to coal in terms of marginal costs, which may increase the load factor of gas plants and thereby reduces their average costs. For an investment decision the windfall profit translates into lower investment cost. Brunekreeft & Twelemann (2005) calculate the entry price, which is the price at which a new investment just recovers full cost.[33] Receiving a number of permits works out as lowering fixed investment costs and increasing variable (opportunity) costs.[34] Lower effective investment costs make it more likely that new plants will be able to compete against existing plants. For existing machines the lower investment costs are bygones and the windfall profits can be passed through to the shareholders. For new entrants it makes a difference in the investment decision. For this reason, the free allocation of permits stimulates entry with new investment.

If the initial allocation is free of charge, money flows into the system. As long as entry is possible and rewarded with new permits, this leads to excessive entry and capacity. In the long run, the profitability of plants is brought back to a normal rate of return by (inefficiently) low load factors. At least initially new entry is likely to be more efficient with lower specific CO_2-emissions and thus existing plants are likely to face the lower load factor; one would anticipate the early retirement of these plants.

Although auctioning the permits is superior from an efficiency point of view, allocating the permits free of charge stimulates new investment (more and sooner) which is good for competition and supply security. The effect on technology is less optimistic. As soon as allocation deviates from 'best practice' (product benchmark) and instead differentiates between different technologies (technology benchmark), the technology choice is distorted. The relative advantage new RES should have under a system of auctioned CO_2 permits vanishes, if the permits are allocated free of charge and according to a technology benchmark. Furthermore, if the permits are allocated

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33 There are two key numbers, reflecting the merit-order effect. For an CO_2 price of less than €30/tCO_2 the entry price is about €52/MWh due to a low load factor. With an CO_2 price of more than €30/tCO_2 the entry price is about €36/MWh, with a high load factor. The numbers are sensitive to assumed fuel prices and efficiency levels. Compare also Pfaffenberger & Hille [2003] for similar findings.

34 An alternative way of reasoning (leading to the same result) is to argue via the revenue side of Net Present Value. Allocating the permits free of charge does not have an effect on expenses, but it does increase market price. Hence, the system will make new investment more attractive than it otherwise would be.

according to a technology benchmark (by and large corresponding to the emission rate of state-of-the-art machines), then replacing an old inefficient, high-carbon machine with a new efficient, low-carbon machine implies less permits, which in turn means smaller windfalls. At the very least, this postpones the replacement.

Art. 10 of the German National Allocation Act specifies a *transfer rule*, which addresses this problem. If an old plant is replaced by a new plant, the permits of the old plant can be transferred to the new plant for four years. In an insightful study, Bode et al. (2005) argue that transfer rule heavily distorts competition as it puts new entrants (who cannot 'replace old machines') at a disadvantage: for the same investment an incumbent replacing its old machine would get more CO_2 permits then an entrant not replacing an old machine. Somewhat surprising though, Bode et.al. (2005) also claim that (with unlimited validity of the transfer rule) the transfer rule does not speed up replacement. This counterintuitive claim seems to be due to fact that the analysis lacks an explicit dynamic factor and thus a timing problem. Explicitly including a dynamic factor and timing (e.g. demand growth or cost-reducing learning) repairs this point and causes the transfer rule to speed up replacement.

Overall we conclude that a system allocating CO_2 permits free of charge (inefficiently) supports competition with new entry and generation adequacy. The effect on the environment is less clear. Having a CO_2-system at all evidently supports the environment, but technology benchmarking may well have detrimental effects. The transfer rule is good for the environment but may damage competition too much.

3.3 Generation adequacy

3.3.1 Hands-off policy on generation adequacy

The power crisis in California in 2000/1, the power black-outs in New York, London, and Italy in 2003 and many near black-outs in recent years triggered concerns about the incentives of the liberalized power markets to provide adequate capacity. The overall issue is reliability, including both generation and networks. We concentrate on generation here; an impression of the network side has been given in section 2.1.4. Reliability in turn covers two aspects: *security* and *adequacy*. Supply security is the ability of the system to respond to short term disturbances; this requires sufficient reserve capacity and is typically the system operators' task. Supply adequacy (or, in our case generation adequacy) reflects sufficient long-term investment in such a way that the system functions under standard conditions; this begs the question as to whether the market provides sufficient incentives to invest.

This is controversial and the impression is that policy makers in the USA are less confident in the market than in Europe. A primary problem is fluctuating and uncertain demand (and of course, the fact that electricity power cannot be stored and the fact that supply should meet demand at all times), which implies that there will be peaking units with a very low load factor. In other words, the costs of a peaking plant should be recovered in only a couple of hours. If we assume, for instance, that a peaking plant has annualized costs of €40,000/MW/a, we need 10 hours per year and a price as high €4,000/MWh to recover costs. If generation units are paid only for real production, then the prices are called energy-only prices. A system of energy-only prices is typically what the spontaneous market design will be.

Theory predicts that scarcity will push up prices, which will attract new investment which in turn will reduce scarcity and so on, until an equilibrium is found. This is convincing, yet there are reasons to be cautious. Individual consumers cannot (at least not in current circumstances) be shut down individually; hence consumers have weak incentives to contract for (reserve) capacity. Two points weaken this argument. First, if large consumers can be shut down individually, the total market may be sufficiently responsive; the question is what is sufficient? Second, developments with so-called smart meters, which can be used to disconnect individual households, are fast. A further argument why markets may be slow to respond to scarcity prices is these very high prices are simply unrealistic [Joskow, 2003]. Joskow & Tirole [2004] point out that even such very extreme situations and subsequent extremely high prices are very sensitive to the discretionary behaviour of the TSO. Furthermore, most systems have a maximum price; in many parts of the USA, bids are capped at $1,000/MWh. And even if they are not capped explicitly, there is justified concern that prices higher than this might trigger government interference. As pointed out in Brunekreeft & McDaniel [2005] this may be a vicious circle ending in a low-capacity equilibrium.

We see the academic controversy reflected in policy, where there is a wide variety of policy measures. In the USA, a system with capacity obligations is popular. In Europe, concern has been expressed by the European Commission with its supply security package of December 2003. Some countries in Europe have explicit policies like capacity payments (e.g. Spain) or reserve contracting (Sweden and the

Netherlands[35]). Most countries however have a hands-off policy: i.e. explicitly doing nothing (except perhaps monitoring) and leaving it to the market (e.g. Norway and the UK).

The German approach is also hands-off although it has not been made explicit. The background is more practical; Germany has a long tradition of excess capacity on which the system still relies and the investment question is not yet urgent. Para. 51 of the Energy Act requires the monitoring of supply security by the Ministry of Economic Affairs, and in the case of installed capacity (taking account of interruptible contracts) not being adequate, para. 53 then allows the government to organize a tender for additional capacity, in line with art. 7 of the EU E-Directive 2003. It is safe to conclude that generation adequacy is not a policy issue in Germany yet.

3.3.2 Generation capacity and investment in Germany

Is this justified? Basically we observe that (as elsewhere) both investment levels and generation reserve margins have dropped in the last 5 to 10 years. However, in recent years, both have been restored. The reserve margin in Germany has been studied closely in Brunekreeft & Twelemann [2005] and it seems that all that has happened is that excess capacity has been reduced without endangering continuity of supply. Yet at some point new investment is required. First, to meet new demand. Second, to adjust to technological progress (certainly eyeing the environment). Third, provided that phasing out goes ahead as planned, to replace the nuclear power plants which are to be decommissioned. Fourth, to replace old and depreciated machines. Table 4 below suggests that a large share of the generation plants in Germany is rather old and will need to be replaced soon.

[35] The system in the Netherlands has been designed but the required additional reserve capacity has currently been set to zero, and hence the system is inactive at the moment.

Table 4: Age of German generation plants

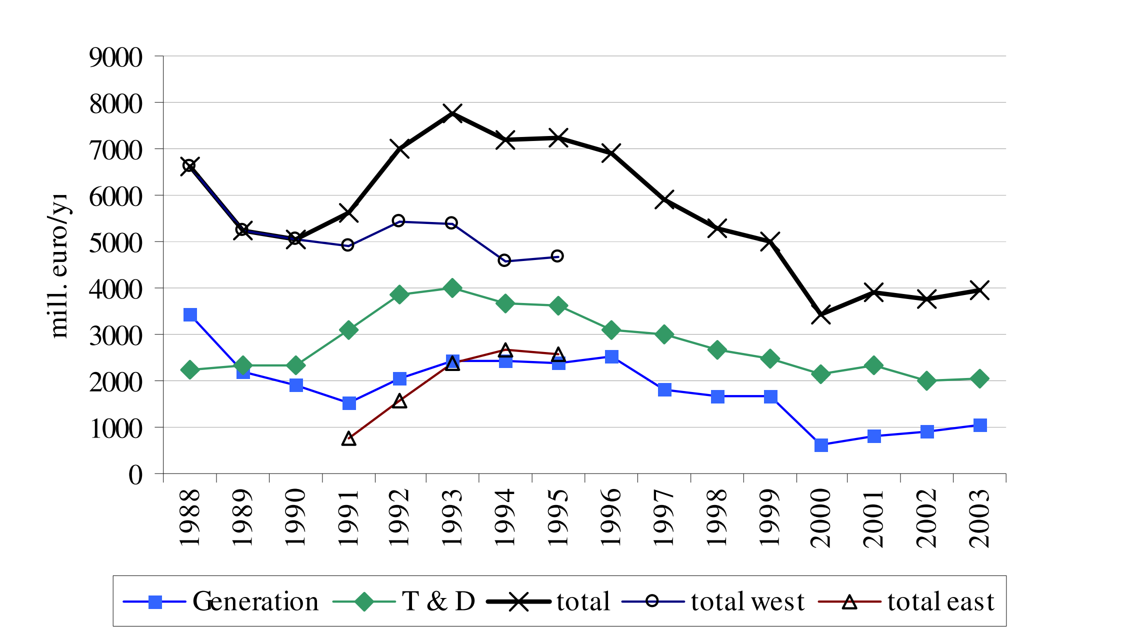
Type	> 30 yrs	30 -10 yrs	< 10 yrs
Hard coal	10635	17457	768
Lignite	9570	6207	5465
Nuclear	2223	21340	0
Gas	7291	6980	3293
Oil	4879	2044	39
Other	183	1109	1853

Source: Ziesing & Matthes, "Energiepolitik", DIW-Wochenbericht 48/2003.

As mentioned before, though, investment activity is picking up[36]. Figure 10 shows how investment fell steeply after the all time high following re-unification. But clearly, the fall halted and in the meantime and investment is increasing again. Further, the increased wholesale prices make new projects attractive and indeed attract new entry. There are projects by companies like Statkraft, yet the most interesting development comes from mainly municipal distributors/retailers joining forces and investing in new generation plants. Examples are Trianel and SüdWestStrom. A reason which is sometimes heard is to reduce the dependence on the big producers, from which we may conclude that competition has not been working all that well. A problem for new entrants has been the availability of sites for power plants. While completely new sites are difficult to find and often meet the resistance of the local public, existing sites are difficult to get hold of because they are in most cases controlled by the incumbents. For example, there was interest from municipal utilities in the south to build a CCGT plant on the Obrigheim site, a decommissioned nuclear plant. Yet EnBW who owns the site, refused to make it available for such a project, putting forward grid-related arguments. Lastly, the regulator and regulation should be expected to ease new entrants' lives and as explained the CO_2 ETS as well as the RES policy appears to suppport new investment. All in all, the German ESI may need new investment but it is likely to come.

[36] See for example the August 2005 investment survey among 200 industry done by ZEW (www.zew.de).

Figure 10: **Investment in the German ESI**



Source: Data from Karl, “Ifo Schnelldienst”, various years.

3.3.3 New capacity: gas or coal?

For several years after liberalisation, gas-fuelled CCGT was seen as basically the only option for new plants. In 1991, the European Commission lifted restrictions on the use of gas for electricity production. Gas prices were relatively low. With CCGT, new gas-fuelled technology was highly efficient. The relatively low capital costs and short construction times and life duation made new gas an attractive investment in the liberalised market.

However, coal and lignite are on the rise again, at least in terms of announcements and expectations. Even EnBW in the south of Germany ponders the possibility of building new coal plants, although not that long ago transportation costs in this region, which is far from both domestic and imported coal, were thought to be prohibitive. CCGT plants still benefit from high fuel efficiency and low capital costs, but the high gas price has turned against it. Gas projects have also suffered from the lack of gas network regulation and problems with third party access, a situation that can be expected to be improved by the new Energy Regulator. This particular problem was presumably worsened by the controversially approved E.On-Ruhrgas merger, in as far as new entry was expected to be with gas-fuelled plant. The European Commission is worried about a high European gas import-dependence (from northern-Africa, Russia and the Middle-East). Alternatives are for instance to rely more strongly on LNG and more on indigenous sources like coal.

On the other hand, as becomes clear from Figure 9 hard coal prices are increasing as well. Heavily increased demand from especially China has increased upward pressure on the coal price. There are also increasing costs of transportation, apparently especially due to the Chinese claim on shipping of steel. It is sometimes expected that the high coal price will not last, due, for instance, to exploitation of new mines and transportation capacity, while gas prices are expected to remain high.

The CO_2 ETS makes coal relatively more expensive compared to gas.[37] However, the CO_2 price must be rather high to have a significant effect. On the other hand, if fuel efficiency increases, ceteris paribus CO_2 emission per MWh goes down. Although the same holds for CCGT, rather strong technological advances are expected in more efficient coal and lignite plants (supercritical plant and clean-coal technology) [cf. e.g. Bode, et. al., 2005].

While both hard coal and gas can be bought on the market and are potential options for new entrants, lignite is a different game. As it is too expensive to transport lignite over long distances, due to its low energy density, lignite plants are generally located right next to the mine, the mines are owned by the generators and the fuel is shovelled from the mine into the plant without going through any form of market. Consequently, the marginal costs of lignite plants are anyone's guess. For new entrants, there is no way they can get access to lignite and new lignite plants will be built by the incumbents. Currently, it is mainly RWE that is about to replace its old plants by new ones.

We conclude that the future of coal as a fuel for the German ESI looks brighter than is sometimes thought. Looking at projects under construction and announced projects from mid 2005, gas and coal have about the same share (see Table 5).

[37] However, coal does not contain methane (CH_4) which puts coal at a relative advantage if methane should be part of an emission scheme.

Table 5: Power plant projects in Germany

Project name/ location	Company	Plant Type/ Fuel	Size in MW	Comments
Hamm	Trianel	Gas-CCGT	800	Under construction. 28 municipal utilities from Germany, Austria and the Netherlands have shares in this project, to go on-online in September 2007
Huerth-Knapsack	Statkraft	Gas-CCGT	800	Project was taken over from Intergen
Lubmin	Concord Power	Gas-CCGT	1200	Under construction
Irsching/ Ingolstadt	Eon/ N-Ergie/ Mainova	Gas-CCGT	800	
Herdecke	Mark-E/ Statkraft	Gas CCGT	400	
Lingen	RWE	Gas CCGT	800 -1000	
Boxberg	Vattenfall Europe	Lignite	700	Additional capacity, not replacing old lignite plants
Neurath	RWE	Lignite	1100 or 2200	Replacing old lignite units
Karlsruhe/ Heilbronn	EnBW	Hard Coal and/or Gas		No final decision on fuel yet, coal would have relatively high transport costs
?	SüdWest-Strom	Hard Coal or Gas	400-800	No final decision on fuel yet, coal would have relatively high transport costs, municipality-based company
?	Trianel	Hard Coal	700-800	As with the Trianel CCGT project, municipal utilities can buy shares in this project
Datteln	Eon	Hard coal	1000	Replacing a 300 MW coal plant
Hamm	RWE	Hard coal	2*750	
Hamburg	Vattenfall Europe	Hard Coal	700	

Source: Company information, various sources

4 Concluding remarks

This contribution examines energy policy in Germany. The primary focus is on the effect of various policies, which directly or indirectly relate to the energy market, on investment in the Electricity Supply Industry (ESI) in Germany. Investment in turn affects competition, environment and supply adequacy. The policies we examine are threefold.

First, we study the policy related to liberalisation and regulation of the ESI. On July 13, 2005 a new Energy Act entered into force implementing the EU Directive of 2003. The key point of the new Energy Act is to remove negotiated Third Party Access and instead establish regulated Third Party Access. It can be concluded that the previous system which did not have effective regulation did not work. Network charges are high both in international comparison and relative to the end-user price. Competitive margins are low, which impedes effective competition. The new system installs a sector-specific regulator (BNA) and regulation. The regulation is as yet cost-based, but the Act explicitly allows the option to switch to ex-ante, incentive-based regulation. In practice this means a shift of emphasis towards ex-ante, forward-looking capping of revenues for a predetermined period and presumably a stronger reliance on benchmarking of different firms.

As set out extensively in this contribution, we expect that the regulation of network access will strongly support the development of competition in both generation and retail; we already observe that investment activity in generation assets is starting to take off. On the other hand, it can be argued for a variety of reasons that the shift towards incentive-based regulation, which aims at short run efficiency, tends to have detrimental effects on (long run) network investment. This can be defended though, because currently the networks are viewed as being in good shape albeit inefficient and the Energy Act does allow quality adjusted regulation.

Second, Germany has a strong tradition of supporting the environment. The policies on renewables (RES), combined heat and power (CHP) and the CO_2 emission trading are dominating the debate at the moment. The support schemes and network-connection arrangements for RES and CHP, although with different background, are generous and should be expected to support further new investment. The costs of the schemes are passed through to end-users and network charges respectively. Examination reveals that the numbers are too small to make RES and CHP responsible for the recent increase of end user prices. The CO_2 price is surprisingly high and as the German power production relies on coal the CO_2 mark up in Germany is high as well. Exactly this seems to explain much of the recent price increase. The system of allocating the CO_2 permits free of charge, whilst inefficient, stimulates new investment and thereby promotes competition and supply adequacy. Oddly, as a consequence of having a technology benchmark, the new investment need not be in clean technology.

Third, despite controversial debate on generation adequacy elsewhere, Germany has no explicit policy on generation adequacy. Leaving the theoretical question as to whether the energy-only market will provide sufficient capacity aside, we observe that capacity margins and investment levels have dropped in the last six or seven years, but have been restored recently. Moreover, generation assets in Germany are old and replacement and modernization are required soon. At the same time, we observe that investment activity (at least announced) is definitely picking up again. Challenging the conventional wisdom that gas will dominate the future, it seems that hard coal has a brighter future than sometimes thought.

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